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| 25.2 | IE-03 | This FAQ is submitted based on the statement in NEI 99-02 Rev 1, page 17, lines 28 - 33:<br><br>"Anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater that 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted."<br><br>The water conditions of Lake Ontario have improved over the years. One of these improvements has been the increased clarity of the water. This increased clarity allows the sun light to penetrate much deeper in all areas of the lake, thus encouraging aquatic growth, such as lake grass. The spring and summer of 2001 have been storm-free on most of Lake Ontario causing little disturbance and turnover of the lake water.<br><br>On July 26, 2001, a significant change in the weather and lake environment caused the station engineers monitoring the condenser efficiency to check the condenser parameters. Due to the influx of lake grass, the delta-T across potions of the main condenser had increased, but remained within environmental release limits. Due to micro-fouling (zebra mussels, silt) in the past, the station is sensitive to lake conditions, however, prior to this event, the station had not experience condenser fouling due to lake grass. In addition, the need to check condenser efficiency with no adverse indication is not proceduralized.<br><br>The delta-T across the affected condenser side improved over the next couple of days as the weather and the lake conditions returned to more normal and the lake grass washed itself from the condenser. However, a down power was needed to clean the main condenser. A decision was made to clean the main condenser when the electric grid loading allowed for it. Discussion with load control dispatchers determined that July 28, 2001, would be the most opportune and economic time to reduce load. The main condenser was cleaned that Saturday morning. At no time between discovery and condenser cleaning did any condenser parameter require a load adjustment other than to improve efficiency as a result of the lake grass influx. Is this greater than 20% power change considered an unplanned power change? | 9/12 Introduced<br>11/15 On Hold<br>12/13 NRC to discuss with resident<br>2/28 On hold<br>3/21 Tentative Approval | Ginna |
| | | **Response**<br>No The influx of lake grass had not caused condenser fouling in the past and was therefore an unanticipated event. The licensee is expected to take reasonable steps to prevent intrusions of lake grass from causing power reductions in the future. | | |

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| 26.6 | MS01<br>-<br>MS04 | **Question**<br><br>General Question: For a single-train support system with redundant active components, does unavailability of one of the redundant active components require one of the trains of the monitored system to be considered unavailable?<br>Station Specifics: The Point Beach component cooling (CC) water system provides a support function for the Residual Heat Removal (RHR) system. The RHR system provides both normal shutdown decay heat removal and decay heat removal during the containment sump recirculation phase of a design basis LOCA.<br>The CC system consists of a single loop with two 100% (redundant) pumps installed in parallel. Each pump is powered from a separate diesel backed bus. Under all license basis conditions (i.e. Chapter 14 analyses), a single pump is capable of providing 100% of the flow necessary to meet the design bases of the plant.<br>Similarly, multiple CC to Service Water (SW) heat exchangers are arranged in parallel, any one of which is fully capable of removing the accident design bases heat loads.<br>The station license considers the possibility of a temporary total loss of CC function due to a single passive failure during the long-term sump recirculation phase of an accident, and finds this acceptable since decay heat removal from containment is available via containment fan coil units. Does unavailability of a single pump and/or heat exchanger in the CC system constitute unavailability of a train of RHR, even though there is no intersystem train dependency? | 10/18 Introduced<br>12/13 Discussed<br>2/28 Licensee to revise | Point Beach |
| | | **Response:**<br><br>No. Due to the redundant active components provided by the CC system design, the decay heat removal function of RHR is assured even when a single failure of a CC component has occurred. There is no intersystem train dependency with this design. | | |

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<tr><td>26.12</td><td></td><td>Appendix D Question<br>The Oconee Nuclear Station has a unique source of emergency AC power. In lieu of Emergency Diesel Generators, Oconee emergency power is provided by one of two identical Keowee Hydro units located within the Oconee Owner Controlled Area. These extremely reliable units are each capable of supplying ample power for the plant loads for all three Oconee units. Additionally, they are also used for commercial generation using an overhead line to the Oconee switchyard.<br><br>Train separation at Oconee is initially established at the three (3) 4160 volt load buses in each unit. These buses are all fed from one of two main feeder buses in each unit, that are both in turn supplied from a single underground power cable from a Keowee unit. This underground path is preferred and is preferentially selected on a loss of offsite power and an Engineered Safeguards signal. If the Keowee unit aligned to the underground path trips, the ONS loads will be automatically transferred to the remaining adjacent Keowee unit. As an additional source of power, the main feeder buses can also be fed from the Keowee overhead power line via the Oconee switchyard.<br><br>The PRA calculations indicate the Underground Path is significantly more important than the Overhead Path, which is susceptible to external events and therefore can be discounted. From the PRA results, it is recommended that safety system unavailability reporting for the MS01 performance indicator be based on the Underground path. PRA calculations support the following thresholds based upon the delta CDF for unavailability of the Underground Path.<br><br><table><tr><th></th><th>Green/White</th><th>White/Yellow</th><th>Yellow/Red</th></tr><tr><td>dCDF limits</td><td>>=1E-06</td><td>>=1.4E-05</td><td>>=1E-04</td></tr><tr><td>Underground Path Unavailability</td><td>2.0%</td><td>4.0%</td><td>10.0%</td></tr><tr><td>Overhead Path Unavailability</td><td>16.9%</td><td>100.0%</td><td>N/A</td></tr></table><br>The Green/White threshold value is consistent with the Maintenance Rule limit for unavailability of the Underground Path. Also, historical unavailability of the Underground Path would place ONS mid-way in the green band, which is consistent with average industry performance for the MS01 indicator. The White/Yellow threshold of 4.0% provides an appropriate white band as compared to the threshold of 5.0% indicated in NEI 99-02 for a system with two trains of Emergency AC equipment. The Yellow/Red threshold of 10% is conservative and is consistent with NEI 99-02 for a system with two trains of Emergency AC equipment. Monitoring the underground path only, are 2.0%, 4.0% and 10.0%, acceptable threshold values for the ONS Emergency Power performance indicator?<br><br>Response:<br>Yes.</td><td>11/15 Discussed<br>12/13 On hold<br>2/28 NRC reviewing</td><td>Oconee</td></tr>
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| 27.1 | MS01 -04 | *Question:*<br>*NEI 99-02, "Regulatory Assessment Performance Indicator Guidelines," under section 2.2 Mitigating Systems Cornerstone, provides the following guidance:*<br>• *The purpose of the safety system unavailability indicator is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents.*<br>• *Off-normal events or accidents are events specified in a plant's design and licensing bases. These events are specified in a plants safety analysis report, however other event/analysis should be considered (e.g., Appendix R analysis)*<br>• *Hours required are the number of hours a monitored safety system is required to be available to satisfactorily perform its intended safety function.*<br>• *A train consists of a group of components that together provide the monitored functions of the system and as explained in the enclosures for specific reactor types. Fulfilling the design bases of the system may require one of more trains of a system to operate simultaneously.*<br>• *The specific reactor type enclosures provide figures that show typical system configurations indicating the components for which train unavailability is monitored. A statement is made that plant specific design differences may require other components to be included.*<br><br>*Plant specific design for the auxiliary feedwater, component cooling water, and essential service water systems provide Appendix R alternate shutdown capability to achieve safe shutdown from the unaffected unit through system cross ties. D.C. Cook Technical Specifications (TSs) incorporate this Appendix R alternate shutdown capability. The focus of the TSs is on the availability of equipment to support the opposite unit when the opposite unit is operating.*<br><br>*Should the availability of Appendix R alternate shutdown capability be monitored and reported for safety system unavailability indicators?*<br>*Response:* | 2/28 Introduced. Licensee to revise | DC Cook |

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| 27.3 | IE02 | Question:<br>Should a reactor scram due to high reactor water level, where the feedwater pumps tripped due to the high reactor water level, count as a scram with a loss of normal heat removal<br>Background Information:<br>On April 6, 2001 LaSalle Unit 2 (BWR), during maintenance on a motor driven feedwater pump regulating valve, experienced a reactor automatic reactor scram on high reactor water level. During the recovery, both turbine driven reactor feedwater pumps (TDRFPs) tripped due to high reactor water level. The motor driven reactor feedwater pump was not available due to the maintenance being performed. The reactor operators choose to restore reactor water level through the use of the Reactor Core Isolation Cooling (RCIC) System, due to the fine flow control capability of this system, rather than restore the TDRFPs. Feedwater could have been restored by resetting a TDRFP as soon as the control board high reactor water level alarm cleared. Procedure LGA-001 "RPV Control" (Reactor Pressure Vessel control) requires the unit operator to "Control RPV water level between 11 in. and 59.5 in. using any of the systems listed below: Condensate/feedwater, RCIC, HPCS, LPCS, LPCI, RHR."<br><br>The following control room response actions, from standard operating procedure LOP-FW-04, "Startup of the TDRFP" are required to reset a TDRFP. No actions are required outside of the control room (and no diagnostic steps are required).<br><br>Verify the following:<br>TDRFP M/A XFER (Manual/Automatic Controller) station is reset to Minimum<br>No TDRFP trip signals are present<br>Depress TDRFP Turbine RESET pushbutton and observe the following<br>Turbine RESET light Illuminates<br>TDRFP High Pressure and Low Pressure Stop Valves OPEN<br>PUSH M/A increase pushbutton on the Manual/Automatic Controller station<br>Should this be considered a scram with the loss of normal heat removal? | 1/25 Introduced<br>2/28 NRC to discuss with resident | LaSalle |
| | | **Proposed Answer:**<br>No, the scram would not count as a scram with a loss of normal heat removal.<br><br>The actions required to restore TDRFPs are not considered to be a diagnosis. The operators are fully trained (classroom and simulator training) to recognize that the TDRFPs trip on high reactor water level and are trained to take the appropriate steps to restore the feedwater pumps as soon as the high reactor level alarm clears. This evolution is a basic operator knowledge item and not a diagnostic for purposes of this indicator. Therefore, this event would not be considered a scram with a loss of normal heat removal, because, the indicator excludes events in which the heat removal path through the main condenser is easily recoverable without the need for diagnosis or repair. | | |

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| 28.2 | MS 01 | Question:<br>Our plant had just completed the monthly EDG load-run surveillance and had passed the plant's load and duration test specification. The EDG was being secured from the test in accordance with the surveillance. Generator real load (kW) was initially reduced, when it was discovered that generator reactive load (KVAR) would not respond to remote or local control inputs. Operations then tripped the generator output breaker and secured the EDG and declared it out of service. Initial trouble shooting of the voltage regulator was performed and the engine was run the next day with similar response to load control. At this point the engine was removed from service for repair of the generator. The root cause evaluation determined that the generator had two shorted coils. The cause of the shorted coils was degradation of winding laminations over time due to poor winding processes at a repair vendor's facility for work performed in 1993. This degradation ultimately resulted in contact between a generator winding and uninsulated wedge block bolting internal to the generator while the engine was being secured following successfully satisfying the monthly surveillance.<br><br>In applying fault exposure hours to this scenario we believe that by meeting the plant's load and duration test specification, during the surveillance, NEI 99-02, Revision 2, page 42 line 32 criterion for successful start and load-run was met. Because the failure occurred during the unload and shutdown portion of the surveillance (the failure's time of occurrence is known), fault exposure is not applicable. The time that the engine was out of service for the initial voltage regulator trouble shooting, the second attempt to run the engine and hours associated with the generator repair are counted as unplanned unavailable hours.<br><br>Have we correctly interpreted NEI 99-02 guidance that fault exposure hours would not be reported in this situation?<br>Suggested Response:<br>Correct. Fault exposure hours are the time that a train spends in an undetected, failed condition. In this situation, the failure's time of occurrence is known. The failure occurred while the engine was being secured during the unload and shutdown portion of the surveillance after the engine passed its load run test and passed the plant's load and duration test specification. | 2/28 Introduced<br>3/21 Discussed | Point Beach |
| 28.3 | IE02 | See attached Question and Response | 3/21 Discussed | Perry |
| 28.5 | MS01 | Question:<br>Treatment of Planned Overhaul Maintenance in the Clarifying Notes section of the Mitigating Systems Cornerstone, Safety System Unavailability, states that plants that perform on-line planned overhaul maintenance (i.e., within approved Technical Specification allowed Outage Time) do not have to include planned overhaul hours in the unavailable hours for this performance indicator under the conditions noted. This section further states that the planned overhaul maintenance may be applied once per train per operating cycle. EDG(s) at Prairie Island are on an 18 month overhaul frequency per T.S.4.6.A.3.a, while the plant operating cycles are typically a month or two longer. Thus, the EDG 18 month overhaul will occur twice in some cycles. If major overhauls, performed in accordance with the plant's technical specification frequency, result in more than one major overhaul being performed within the same operating cycle, can both of these overhauls be excluded from counting as planned unavailable hours?<br>Response<br>Yes, as long as the overhaul maintenance is completed within an established preventive maintenance program and the overhaul is completed within the specified technical specification frequency, the unavailable hours do not need to be counted. | 2/28 Introduced | Prairie Island |

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| 28.6 | OR01 | Question:<br>While in a high radiation area (HRA) removing scaffold, workers inadvertently dislodged lead shielding around a hot spot flush rig and created conditions that required posting a locked HRA (dose rates in excess of 1 rem per hour). Several minutes later when they moved to a location closer to the hot spot, the three scaffold workers received dose rate alarms. Upon receiving the alarms, they immediately left the area and the alarms cleared. After reading their dosimeters and verifying that they had not received any unexpected dose, they discussed the alarms with their supervisor and concluded that the momentary alarm was not unexpected since general area dose rates in the HRA could have caused the alarms. When the three workers attempted to log out of the RCA at the access control point, Health Physics (HP) discovered that all three individuals received a "Dose Rate" alarm on their electronic dosimeters. Independent from the ensuing exposure investigation, and approximately within the same time period (within minutes), a HP technician found radiation levels in excess of 1 rem per hour when performing a routine survey to support removal of the hot spot flush rig. The HP technician established proper controls and posting for the area and discovered that local shielding around the flush rig had been disturbed. Does this count against the technical specification high radiation area occurrence PI?<br>Licensee Response:<br>No, this occurrence is not "countable" against the technical specification high radiation area occurrence PI. Prior to the inadvertent change in radiological conditions, the area was correctly posted. The change in conditions was identified within a very short time frame during routine HP survey activities to support work in the area, and timely corrective actions were taken by the HP organization to establish the proper controls and posting. Although the workers failed to recognize that their work activities caused a change in radiological conditions, HP personnel responded properly to the dose rate alarm condition and their investigation would have independently resulted in establishing the proper controls in a timely manner. This incident constitutes a Human Performance issue in that the individuals failed to immediately notify HP upon receiving the alarms, but should not count towards the radiological PI for failure of HP to control access to a technical specification high radiation area. | 2/28/02 Introduced<br>3/21 Discussed | St. Lucie |
| 28.7 | BI 02 | Question:<br>During maintenance, water from the charging pump suction header was aligned to a relief valve which relieves to a boric acid tank. This relief valve unexpectedly lifted below the setpoint tolerance. The relief valve was passing about eighteen gpm to the boric acid tank based on calculations using volume control tank level trend. The source and collection point of the leakage was unidentified until the time that realignment secured the leak. A Notice of Unusual Event was declared due to reactor coolant system (RCS) unidentified leakage greater than or equal to 10 gpm. The duration of this event was approximately thirty-five minutes.<br>1. The leak occurred from a piping system outside containment that communicates directly with the RCS (e.g., letdown to the volume control tank). The leak was from a source that would not be automatically isolated during a safety injection signal. The leakage was collected in a tank outside containment that is not considered in the baseline as identified leakage when performing the Technical Specification RCS Leakage surveillance procedure. Note that the WOG STS definition of Identified Leakage is "Leakage that is captured and conducted to collection systems or a sump or collecting tank." Is this leakage to be considered for inclusion in the RCS identified leakage PI?<br><br>2. Is it intended that "event based" leaks of short duration that are diagnosed and corrected between performances of Technical Specification required calculations of RCS leakage be evaluated by the Significance Determination Process only and thus not included in the RCS leakage PI? | 2/28/02<br>Introduced | McGuire |

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| | | Response<br>1. No. The TS methodology provided by the RCS Leakage Calculation Procedure is to be used. The source and collection point of the leakage in this example were unknown during the time period of leakage, and the actual collection point was not a monitored tank or sump per the RCS Leakage Calculation Procedure. Therefore, this is not considered RCS identified leakage to be included in PI data.<br>2. Yes. Short term events where it is either not practical or conditions do not permit performing the RCS Leakage Calculation Procedure are not to be included in the RCS Identified Leakage PI. Examples include not meeting the steady state conditions defined in the procedure prerequisites, or the duration of the leak being significantly less than the minimum time requirement for monitoring leakage as specified in the RCS Leakage Calculation procedure. In the example, conditions were stable; however, the duration of the leak was significantly less than the time period necessary to allow completion of the RCS Leakage Calculation Procedure. | | |
| 28.8 | EP 01 | **Question:**<br>At one point in the 2001 Off-Year Exercise, a wrong sub-area was identified as part of the affected PAR determination. This PAR determination, including the incorrectly identified affected sub-area, was approved for inclusion in the State notification. The State notification was made to the simulated State responder as approved and in a timely manner. Subsequently, the error in the PAR was discovered and a corrected PAR was developed, approved, and communicated to the simulated State responder, beyond the original 15 minutes.<br><br>This event was initially counted as three successes out of four opportunities (a successful emergency classification, a successful emergency notification, an unsuccessful PAR determination, and a successful PAR notification). Through discussions with the Senior Resident NRC Inspector, the question was raised concerning whether the paragraph on page 81, lines 6-8, of NEI 99-02, Revision 1 (page 89, lines 4-5 of Revision 2), applies to errors made during PAR determination. The paragraph is clear concerning classification errors, in that one classification error does not cascade to the notifications and PAR. However, a similar paragraph addressing errors made in PARs determination was not found in NEI 99-02. Additionally, the definition of *Accurate* states that the notification form should be completed "appropriate to the event," rather than appropriate to the understanding of the event at that time.<br><br>Because the issue had not been resolved at the time of the fourth quarter 2001 NRC PI submittal, this event was reported as two successes out of four opportunities (a successful emergency classification, a successful emergency notification, an unsuccessful PAR determination, and an unsuccessful PAR notification). This FAQ was developed and submitted to clarify whether the PAR notification is considered successful if the PAR information, including the incorrectly identified affected areas, is communicated as approved.<br><br>For a failure to properly identify the affected areas for a PAR development, is the notification considered successful if the information, including the incorrectly identified affected areas, is communicated as approved?<br><br>Response:<br>Yes, for a failure to properly identify the affected areas for a PAR development, the notification is considered successful if the information, including the incorrectly identified affected areas, is communicated as approved. The paragraph describing an incorrect classification as "only one failure" was intended as an example. The situation with PARs is analogous to that described in NEI 99-02 as applied to classification of an event. The Performance Indicator result should be an incorrect opportunity for development of the PAR and a successful opportunity for notification of the PAR (in addition to the successful emergency classification and emergency notification). | 2/28/02<br>Introduced | Quad Cities |

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| 28.10 | MS01 -04 | Question<br>The guidance in the unavailability portion of NEI 99-02 states that operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e. the restoration actions are virtually certain to be successful during accident conditions). In this context, what does the word "diagnosis" mean? | 2/28 Introduced<br>3/21 To be rewritten | PSEG |
| | | Response:<br>Diagnosis is the investigation or analysis of the cause or nature of a condition. In the context of the unavailability PI, diagnosis refers to activities that are required to determine what actions need to be taken to mitigate the condition. It includes activities such as troubleshooting and research into design documentation. Responding to alarms and following written procedures where success is a virtual certainty is not considered to be diagnosis. If the licensee and the resident inspectors do not agree if the activity in question is considered to be diagnosis, an FAQ should be submitted.<br>Alternate Response:<br>Diagnosis: An investigation or analysis of the cause of a condition, situation or problem. For purposes of the performance indicators, the following guidelines apply:<br>1. A control room operator's use of information available to her/him in the control room does not constitute diagnosis if the first attempt (a single action or a few simple actions) to correct the condition, situation or problem from the control room is successful. Identification of the condition and determination of the appropriate corrective actions together should require collecting only a few data points. If more extensive data collection is required, because of conflicting data for example, this would be considered diagnosis.<br>2. If the control room operator's first attempt to correct the condition, situation, or problem is unsuccessful, any further actions would be considered diagnosis.<br>3. *The fact that a*~~Any~~ procedure ~~that~~ provides a list of alternative actions to be taken in an attempt to correct the condition, situation or problem ~~is deemed to be~~ *does not necessarily mean that the procedure is* diagnostic in nature. However, if in following such a procedure the operator's first attempt is *not* successful, *further actions* ~~this~~ would ~~not~~ constitute diagnosis. *Likewise, if extensive data collection is required to determine which one of the alternative actions should be taken, this would constitute diagnosis.*<br><br>The intent of this paragraph is to allow credit for operator recovery actions when the condition, situation or problem can be quickly identified from indications in the control room and the necessary corrective actions can be promptly (or easily, as applicable) performed in the control room. | | |
| 29.1 | MS 01-04 | Question:<br>In the Mitigating Systems Performance Indicators, fault exposure hours are used to measure the amount of time a train is in an undetected, failed condition. Many quarterly surveillance tests require a certain pump run duration (not required by Technical Specifications) to reach stabilized conditions to allow maintenance personnel to trend parameters and performance. During one such test, a pump started and ran normally until it had to be secured just minutes prior to reaching stabilized conditions, because of degraded pump performance. The subsequent investigation revealed that a failure mechanism was introduced into the pump during the last pump overhaul. The investigation also revealed that the pump had been started, run successfully several times for several hours, and satisfied surveillance requirements on multiple occasions since the overhaul. In this case, was the pump in an undetected, failed condition prior to failure being observed? | 3/21 Introduced | Calvert Cliffs |

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| | | Response:<br>Although the pump was in a degraded condition, it was not in an undetected, failed condition since the pump was successfully started and able to satisfy surveillance requirements on multiple occasions since the overhaul. Therefore, no fault exposure hours are incurred as the failure occurrence time and the failure discovery time were at the same time. | | |
| 29.2 | MS 01-04 | Question:<br>The Mitigating Systems Unavailability Performance Indicators monitor the readiness of important systems to perform their safety function in response to off normal events or accidents. However, the guidance in NEI 99-02 does not stipulate for what period of time a system has to be able to perform its safety function. Typically, surveillance tests only run the train for a small fraction of the full "mission time" that a train may be required to operate in an accident condition. Degraded conditions that increase the failure likelihood could result in a reduction in the ability of a system to perform its safety function. When evaluating estimated exposure hours, is it appropriate to consider the completion of a successful surveillance test as evidence of the ability to perform the safety function given that the failure condition could have been discovered during the test? This would limit the fault exposure hours to no more than the last successful surveillance test that was capable of identifying the failure. | 3/21 Introduced | Calvert Cliffs |
| | | Response:<br>Yes, if the last successful surveillance test could have identified the failure. Surveillance tests are designed to provide a reasonable assurance that the system, train, or component can perform its safety function. It is not necessary for the surveillance to prove whether the component could have operated for the full "mission time." A successful surveillance test demonstrates that the degraded condition was not so severe that it would result in immediate safety function failure. | | |
| 29.3 | IE03 | Question:<br>The James A. Fitzpatrick plant underwent a number of downpowers during significant storms on Lake Ontario in the winter 2000/2001 season. The downpowers were undertaken to prevent exceeding environmental discharge limits, after the main condenser had fouled due to influxes of zebra mussels<br><br>A root cause analysis conducted on the downpowers pointed out possible design and maintenance actions to improve the system's resistance to zebra mussel and debris intrusion.<br><br>Monitoring of lake water sample veliger population, an advance indicator of zebra mussel population, shows that in 1999, the veliger population was quadruple the worst previous year (1996) and a factor of almost 10 higher than 1998. The latest full season measurement (2001) shows veliger population to be about one-third the maximum observed in 1999.<br><br>Additional downpowers due to condenser fouling have not been seen since the improvements were made to the screenwash system, but the ability of the upgraded intake screen system to withstand zebra mussels at the populations seen in 2000 is still not known.<br><br>Should a downpower originally not counted as an unplanned power change due to an environmental cause, which may have been prevented by subsequent enhancements in design and maintenance of the plant's intake system count as an unplanned power change under NEI 99-02? | 3/21 Discussed | JAF |
| | | Response:<br>No, the cause of the downpower was rooted in environmental changes that required enhancements to the material condition and design of the plant's intake system to allow these unprecedented environmental changes to be handled without fouling the condenser. | | |

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| 29.4 | MS01 -04 | Appendix D Question<br>This question seeks an exemption from counting planned overhaul maintenance hours for a support system outage at the Grand Gulf Nuclear Station (GGNS).<br><br>At GGNS, the Safety System Water (SSW) system provides Ultimate Heat Sink supply for the ECCS systems, through three divisions:<br><br>▪ SSW A supplies Division 1 Emergency Diesel, Residual Heat Removal (RHR) A and Low Pressure Core Spray.<br>▪ SSW B supplies RHR B, RHR C and Division 2 Emergency Diesel.<br>▪ SSW C supplies High Pressure Core Spray (HPCS) and Division 3 Emergency Diesel.<br><br>The Emergency Diesels, RHR and HPCS are all Mitigating Systems and are monitored systems as defined in NEI 99-02. SSW is a support system as defined in NEI 99-02 and is monitored to the extent that it affects the monitored Mitigating Systems.<br><br>In 1994, periodic testing of the SSW pumps identified that shaft column fasteners had washers that had deteriorated to the point that the deep draft pump column had grown in length, allowing the impeller to rub on the bottom of the pump casing. The root cause determined that the washers had deteriorated due to galvanic corrosion set up by incompatible material between the pump shaft and the fasteners which was compounded by the poor water quality in the system. These fasteners were replaced on line in 1995 with like-for-like replacement of old materials while new pumps were designed and fabricated.<br><br>The 5-Year Business Planning process established 2002 for SSW A and B pump replacements and 2003 for the SSW C replacement. Work planning and business considerations determined that SSW A and SSW B pumps would be replaced in January and February 2002. Work planning also determined that the pumps could to be replaced on line within the Tech Spec LCO time (72 hours). Work duration was estimated to be 40 hours for each pump.<br><br>A quantitative risk analysis was performed. Due to the complexity and uniqueness of the work, the SSW outages were planned separately from the system outages they support. That is, no parallel Emergency Diesel or RHR outage work was to be scheduled with the SSW outages. The analysis showed that the planned configuration was acceptable from a Regulatory Guide 1.177 and 1.174 standpoint. For example, the incremental conditional core damage probability, ICCDP, is less than 1E-7, and the delta CDF (core damage frequency) is less than 2E-7/yr for this maintenance<br><br>SSW A and B pumps were changed in the first quarter 2002. Approximately 63 unavailable hours were incurred in the work. As a result of pump change-out, the reliability of the SSW system will be improved as the upgrade in pump material will reduce the amount of fastener deterioration to a negligible level. The new pumps are expected to last the life of the plant and should reduce any future out of service time and inspection requirements due to the improved materials compatibility.<br><br>Based upon the above description, should the planned overhaul maintenance hours for the SSW system pump A and B replacements be counted in determining the PI values for Emergency Diesels, RHR and HPCS? | 3/21 Introduced | GGNS |
| | | Response<br>This activity qualifies as a unique plant specific situation as described in NEI 99-02 section for the Treatment of Planned Overhaul Maintenance.. For this plant specific situation, the planned overhaul hours for the SSW system pump A and B replacements may be excluded from the computation of monitored system unavailabilities. | | |

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| 29.5 | EP01 | Question:<br>During an EP drill/exercise scenario, a licensee will implement their procedure(s) and develop appropriate protective action recommendations (PARs) when valid dose assessment reports indicate EPA protective action guidelines (PAGs) are exceeded. A question arises when a scenario identifies that the PAGs will be exceeded beyond the 10 mile emergency planning zone (EPZ) boundary. Should the licensee count the development of the PAR(s) [or the lack thereof] beyond the 10 mile EPZ as an EP Drill/Exercise Performance (DEP) PI opportunity, due to their "ad hoc" nature? | 3/21 Introduced | NRC |
| | | Response:<br>The licensee's requirement to develop and communicate a PAR is not limited to the 10 mile plume exposure EPZ. Beyond this distance, actions are to be taken on an ad hoc basis using the same considerations that went into the development of the predetermined protective actions. If a scenario identifies that dose assessments support the need for PAR development beyond the 10 mile plume exposure EPZ, then the licensee shall develop and communicate such PAR (within the same time goals as the plume EPZ). It is expected that this PAR development and communication has been contemplated by the scenario with an expectation for success and criteria provided. With all that in place, this constitutes a PI opportunity as defined in NEI 99-02. It should be noted that the licensee has the latitude to identify PI opportunities prior to the exercise and may choose to not include a PAR beyond the plume EPZ as a PI opportunity due to its ad hoc nature. Also, separate from the identification of the PAR development, is a PI opportunity associated with the timeliness of the communication of the PAR. Again, the licensee has the latitude to identify the timeliness of the communication as a PI opportunity or not. However, whether a PI opportunity is identified or not, it does not relinquish the evaluation by the NRC and the licensee of the PAR development and its timely communication. Further, the NRC will evaluate the subsequent ability of the licensee to identify and critique unacceptable exercise performance with regard to PAR development and communication. | | |
| 29.6 | IE02 | Question:<br>1) A S/G perturbation occurred because of rain-damaged main feed water pump turbine speed control circuitry. Due to rainwater in the control panel, one main feedwater pump (2B) sped up uncontrollably and main feedwater pump A slowed down to compensate for 2B. This resulted in a Hi Hi level (P-14) in the 2B S/G.<br>At the time of the event, the licensee did not know if both pumps' speed control circuitry were affected/damaged by rain water. The licensee discovered via troubleshooting that pump 2A was not affected. Initially, the operators had placed both pumps in manual control before the reactor tripped in an effort to gain control of the pumps. The speed of the pumps was cycling uncontrollably (while in auto control) due to the 2B feedwater pump's damaged speed control circuitry. Additionally, the 2A pump had a transmitter replaced, while down, for the condenser pressure. The licensee decided to keep the 2A pump off line since the 2B pump was damaged. They did not want to potentially risk automatic initiation of auxiliary feedwater, due to main feed unavailability, if the 2A pump would have been lost due to another occurrence.<br>Should this count as a scram with loss of normal heat removal?<br>2) At what point does the NRC require equipment to be available – at the time of the occurrence or after troubleshooting has been completed? | 3/21 Introduced | NRC (Catawba) |
| | | Response:<br>1) Yes, because the operator was unaware that the 2A pump was available. When the operator noticed the uncontrolled speed of both pumps, it was not known whether pump A, pump B, or both pumps were damaged. Diagnosis was required to determine that pump A was indeed available. NEI 99-02 guidance is clear on the criterion used to count transients against this PI: "…conditions that occurred and cannot be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path."<br>2) The operator must be aware, at the time of the occurrence, that the equipment is available. If this is not known, the equipment is considered to be unavailable. | | |
| 29.7 | IE 03 | *See Below* | | *Turkey Point* |

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| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
|---|---|---|---|---|
| *29.8* | *IE 03* | *Question:*<br>*At approximately 2243 hours on September 24, 2001 the number 2 Station Power Transformer in the Salem Switchyard experienced an electrical fault on one of its associated surge arresters. The failure of this surge arrester resulted in the loss of both the number 2 and 4 main station power transformers and station power transformers 12, 14, 22 and 23. As a result of the loss of these transformers each Salem Unit lost three of the six condenser circulating pumps. Additionally, Salem Unit 1 lost power to its circulating water traveling screens, as well as the sensing instrumentation for the differential pressure across the traveling screens. Upon loss of power to the sensor, the screen delta p indication in the Control Room shows screen delta p as being in the acceptable range, regardless of actual screen delta p. With only three of six circulating water pumps operating per unit, both Salem units reduced electrical load to maintain main condenser vacuum. Following the completion of the power reduction, Salem Unit 1 personnel restored electrical power to the Unit 1 circulating water bus and the circulating water traveling screens. Because of the loss of power to the traveling screens, detritus buildup caused a high differential pressure on one of the remaining screens. Shortly after the power was restored to the traveling screens, one of the three remaining circulating water pumps tripped due to high differential pressure across its associated traveling screen. Because of the loss of power to the sensing instrumentation, this condition was not detected. As a result of this additional loss of a circulating water pump and the resultant decrease in condenser vacuum, Salem Unit 1 licensed control room operators initiated a manual trip in accordance with the guidance provided in the abnormal operating procedure at 2351, on September 24.*<br><br>*Salem Unit 2 circulating water traveling screens were unaffected by the loss of the 2 SPT, therefore the power reduction was sufficient to maintain main condenser vacuum.*<br><br>*Does this event meet the criterion in NEI 99-02 that states "Off-normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only." Or are the causes of the downpower and the scram sufficiently different that an unplanned power change and an unplanned scram must both be counted.* | *4/25 Introduced* | *Salem* |
| | | *Response:*<br>*This should be treated as one continuous event. The loss of the station power transformer resulted both in the loss of three of the circulating water pumps and in the loss of power to the traveling screens, which led to the loss of the additional circulating water pump. Therefore, the cause of both the power reduction and the scram was the electrical fault. Only the scram should be counted in the performance indicators.* | | |

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<table>
<tr><th>Temp No.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td>29.9</td><td>IE03</td><td>
NEI 99-02, Rev 2, states that anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.
At Salem, this type of problem is caused by high river grass concentrations biofouling the heat exchanges, coolers, and condensers. Salem Generating Station has a number of methods to determine the possibility of high biofouling, in order to prevent an unplanned shutdown. These methods include regular sampling to determine river grass concentration, visual confirmation of excess river debris, an excessive Service Water Traveling Screen carryover, and high dP across heat exchangers and/or pumps. In the event of high river grass triggered by these methods, procedural instructions (SC.OP-AB.ZZ-0003(Q), Component Biofouling) are in place to initiate preventative actions to reduce biofouling. Over the past few months, the level of detritus has frequently risen above the Action Level I state, described in SC.OP-AB.ZZ-0003(Q), Component Biofouling, resulting in increased preventative actions. Unfortunately, high river grass concentrations and the biofouling of necessary equipment cannot be predicted.
On February 26, and again on February 28, Salem 1 reduced power to clean the 13A Condenser Water box due to the accumulation of marine debris and biological contaminants on the 13A Circulating Water Pump Traveling Screen. The 13B Circulating Water Pump had been out of service for maintenance in preparation for the upcoming grassing season. A downpower is procedurally required in situations like this when there are no operating Circulating Water Pumps (13A and 13B) in a Condenser Shell.
Concentrations this year began to increase in early October, decrease in early December, and increase again in mid-February. In normal years, the high season was only spring, which was caused by ice thawing in the marshes. That type of river grass is commonly local marsh grass. The type of river grass seen this year, sertularia argentea "Garland Hydroid" and garveia franciscana "Rope Grass", are common to the Chesapeake Bay but have not previously been this abundant in the Delaware Bay. According to Dr. Dale Calder, author of <u>Hydroids and Hydromedusae of Southern Chesapeake Bay</u>, the type of hydroids the Delaware Bay is experiencing are common in high salinity water (ca. 13-30 o/oo) and is active from late September to early June. The observance of high salinity in the Delaware River this year may be attributed to the drought conditions observed over the past few months.
The following table indicates the river grass sample concentration, expressed in Kg/million cubic meters, for the time period in the question. The rapidly increasing levels contributed to the biofouling, which required the downpower.
<table>
<tr><td>2/18/02</td><td>328</td></tr>
<tr><td>2/21/02</td><td>624</td></tr>
<tr><td>2/22/02</td><td>488</td></tr>
<tr><td>2/24/02</td><td>399</td></tr>
<tr><td>2/26/02</td><td>1149</td></tr>
<tr><td>2/28/02</td><td>1809</td></tr>
<tr><td>3/2/02</td><td>2326</td></tr>
<tr><td>3/4/02</td><td>5133</td></tr>
</table>
Do these two examples need to be reported as Unplanned Power Changes?
</td><td>4/25/02</td><td>Salem</td></tr>
</table>

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | *Response:*<br>*No. These two examples represent power changes in response to expected accumulation of marine debris that cannot be predicted in advance. The response is proceduralized, and the operators followed their procedures. The environmental conditions cannot be predicted, but were appropriately monitored and the operator response was in accordance with expectations.* | | |
| *29.10* | *IE 03* | *Question:*<br>*NEI 99-02, Rev 2, states that anticipated power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.*<br><br>*NEI 99-02, Rev 2, does not discuss whether the power changes associated with these FAQs should be counted while awaiting disposition. Is it satisfactory to state in the comment field that a FAQ has been submitted, and not to include the power changes in the PI calculation?*<br>*Response:*<br>*Yes. The comment field should be annotated to state that a FAQ has been submitted. If the licensee believes that this exclusion applies, it is not necessary to include them in the PI calculation. The report can be amended, if required, at a later date.* | *4/25 Introduced* | *Salem* |
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FAQ 28.3

Plant Submitting FAQ: Perry

This event was initiated because a feedwater summer card failed low. The failure caused the feedwater circuitry to sense a lower level than actual. This invalid low level signal caused the Reactor Recirculation pumps to shift to slow speed while also causing the feedwater system to feed the Reactor Pressure Vessel (RPV) until a high level scram was initiated.

Within the first three minutes of the transient, the plant had gone from the Level 8 (Reactor Vessel Water Level – High, Level 8) which initiated the scram, to Level 2 (Reactor Vessel Water Level – Low Low, Level 2), initiating High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) injection, and again back to Level 8. The operators had observed the downshift of the Recirculation pumps nearly coincident with the scram, and it was not immediately apparent what had caused the trip due to the rapid sequence of events.

As designed, when the reactor water level reached Level 8, the feed pumps tripped, including the Motor-Driven Feed Pump (MFP). The pump control logic prohibits restart of the feed pumps until the Level 8 signal is reset. (On a trip of one or both turbine feed pumps, the MFP would automatically start, except when the trip is due to Level 8.) All three feedwater pumps (both turbine driven pumps and the MFP) were physically available to be started from the control room, once the Level 8 trip was reset. Procedures are in place for the operators to use the MFP or the turbine driven feedwater pumps.

Because the cause of the scram was not immediately apparent to the operators, there was initially some misunderstanding regarding the status of the MFP. As a result of the initial indications of a plant problem (the downshift of the recirculation pumps), some operators believed the MFP should have started on the trip of the turbine driven pumps. This was documented in several personnel statements and a narrative log entry. Compounding this initial misunderstanding was a MFP control power available light bulb that did not illuminate until it was touched. In fact, the MFP had operated as it was supposed to, and aside from the indication on the control panel, there were no impediments to restarting any of the feedwater pumps from the control room. No attempt was made to manually start the MFP prior to resetting the Level 8 feedwater trip signal.

As indicated above, reactor vessel water level had been raised back to Level 8 by injection from the HPCS and RCIC systems, precluding restart of the feedwater pumps (including the MFP) (due to being at Level 8). During this period when the MFP could not be started due to the high level condition, the control room dispatched in-field operators to the MFP, where no abnormalities were found with the pump or breaker. Four minutes later, a log entry recorded that the pump was ready for start. The MFP was started 14 minutes later (30 minutes after the scram), in accordance with SOI-N27, Feedwater System, Section 4.10, Motor Feed Pump Manual Startup. This procedure includes steps to verify the MFP control switch is off, verify the Reactor Hi Level Trip Reset lights are de-energized (or press the applicable reset pushbutton), and place the control switch to start. No problems were found or experienced with the operation of the MFP. Therefore, the plant responded as designed. During the transient, the RCIC system was in service to maintain reactor vessel water level.

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In summary, feedwater flow using turbine driven feedwater pumps or the MFP was easily recoverable from the control room after the Level 8 trip was reset. The turbine driven feedwater pumps were available to be started from the control room per plant procedure. There was no problem with MFP since it simply needed to be reset prior to being started. Before the MFP was started, reactor water level was controlled and maintained by Reactor Core Isolation Cooling. Following reset of the Level 8 signal, the MFP was started from the control room and operated as expected.

Question: Does the above described scenario count as an Unplanned Scram with a Loss of Normal Heat Removal?

Proposed Response: No. The Feedwater system functioned as designed, and the normal heat removal pathway was easily restored from the control room. Even though there was a very minor complication with recovery of the MFP that did not impact its availability, the turbine driven feedwater pumps remained available for operation from the control room. Therefore, the feedwater flow could easily be recovered from the control room without the need for diagnosis or repair.

Discussion:

For the Perry plant, the actions necessary to recover the MFP were proceduralized and uncomplicated. Additionally, both turbine driven feedwater pumps were available for operation from the control room if desired. The actions taken by the control room operators in this event also demonstrate appropriate command and control following a major plant transient. It would be inappropriate to apply some apparent urgency to recover the feedwater pumps in such an event. Since the RCIC system was operating and providing vessel inventory, the operators did not need to urgently restore the feedwater pumps, and it would have been inappropriate to do so. While there may have been some initial confusion about why the MFP had not started when the turbine driven feedwater pumps tripped on high reactor vessel water level, normal feedwater flow remained available throughout the event from either the turbine driven pumps or the MFP. Therefore, this should not count as a loss of normal heat removal.

*29.7 IE 03 Turkey Point*

*Plant surveillance procedure 3-OSP-090.2, Main Electrical Generator Hydrogen Leakage Calculation is performed on a weekly basis. Data is gathered on the weekend by operations. Calculations and tracking are performed by the System Engineer each Monday morning. During the past 17 months, hydrogen leakage on the Unit 3 main generator ranged about 800 to 1300 $ft^3$/day. This leakage was due primarily to a known bad hydrogen seal on the north end of the generator. This hydrogen was being safely discharged through the seal oil vapor extractor vent. Repair of this leak was planned for the upcoming refueling outage.*

*Hydrogen consumption by the Unit 3 main generator during the weekend of 07/07/01 increased significantly. The calculated consumption per 3-OSP-090.2 was 1665 $ft^3$/day. This is in excess of the typical Westinghouse generator leakage and a sizeable increase of the trend for Unit 3. On 07/11/01 the system engineer initiated Condition Report (CR01-1364), and a concerted effort began to identify the source of the leak.*

*During the week of 07/11/01, the Engineering Systems Manager and the System Engineer briefed the Plant Manger on the leakage. During this meeting the possibility of a unit shutdown to effect repairs was recognized and discussed. Since no administrative limit on hydrogen leakage had been previously established, the Plant Manager established criteria for unit shutdown. The criteria was:*

1) *Leakage not attributed to the seal becoming greater than 2000 $ft^3$/day (approx. 3000 $ft^3$/day total) AND there was evidence of hydrogen pooling in any area around the generator in excess of 50% LEL,*
2) *an unisolable leak that could not be repaired on-line*
3) *a leak that was rapidly degrading.*

*The decision was made to pursue on-line repairs, as long as conditions permitted and to shutdown if on-line repairs could not be performed.*

*From 07/11/01 through 07/28/01 extensive system checking was performed by Engineering and Maintenance personnel. All valves and devices were inspected sniffed and snooped. Additionally, accessible piping was checked hand over hand. The known leak via the seal oil system was re-quantified and ruled out as the source of the new leakage. During this period, several minor leaks were identified and isolated or repaired.*

*The Main Generator leakage data gathered on 07/28/01 showed leakage on Unit 3 had increased to 2091 cu ft/day. Air movers were installed to draw off hydrogen gases from areas around the generator. The generator skirt access plates, doors, etc. on the turbine deck were removed/opened to sample that space and prevent hydrogen pooling (the turbine building is an "open air" design). No evidence of hydrogen pooling was found. System inspections continued and a cap was installed down stream of valve 3-100-23-1 to isolate a minor leak there. Scaffolding was ordered built to access the belly of the generator so that the penetrations could be inspected.*

*On Saturday, 08/04/01 the hydrogen leakage data showed a leak rate of 3015 cu ft/day. The hydrogen dryer was isolated. No evidence of hydrogen pooling was found.*

*On Monday 08/06/01 the hydrogen leakage data showed a leak rate of 2840 cu ft/day, only a slight decrease. The Plant Manager ordered daily calculations and contingency plans for shutdown repairs if the leak was found to be unisolable. Scaffolding was in place under the south end of the generator and an extensive inspection of the generator system was performed, but no additional leaks were found. The presence of hydrogen was measured in that vicinity at 8% LEL, but no source could be pinpointed.*

*On Tuesday 08/07/01, operations began methodical monitoring of the leak rate by taking data readings every 6 hours. Additional scaffolding was erected beneath the center section of the generator to allow leakage checks of the hydrogen system piping penetrations. Thermographic images were taken of the area under the generator, but no evidence of leaks were found.*

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*On Wednesday 08/08/01, the leak rate was calculated to be 3001 cu ft/day, the scaffolding extension for the full length of the generator was completed. New high sensitivity hydrogen detection equipment was received and put to work. Engineering and Maintenance continued testing for leaks and evidence of pooling. The Isophase ducts were sampled but no hydrogen found. Each generator penetration was snooped and sniffed. The length of each pressurized hydrogen line, paying particular attention to welds and valves, was sniffed and snooped. Some additional minor leaks were found.*

*Engineering personnel then found a large leak on the generator lead box. Cracking was evident between the bottom flange and vertical member weld on the southwest corner. Investigation by plant personnel determined that a fillet weld at the base of the collar of the main lead box assembly was cracked. The crack appeared to be several inches in length and seemed to go around the lower southwest corner of the box. To ensure safety, additional air movers were installed to dissipate the hydrogen gas.*

*Engineering personnel were directed by plant management to develop two specific repair methods:*

A) *a temporary repair method to be worked on-line and*
B) *(as a parallel effort) a repair method to be performed off-line.*

*Plan A, the on-line repair method, proposed using strong backs and sealing material, mechanically wedged or clamped against the crack and then filled with Fermanite. Plan B, the off-line repair method, proposed a weld overlay. Additional scaffolding was erected to safely reach the lead box to support either activity.*

*On Thursday 08/09/01, the leak rate was calculated to be 4421 cu ft/day. Upon closer examination of the crack, engineering determined that Plan A, the on-line repair method, was not viable. Plan B, which used welding, was judged the only effective repair method. Plan B required the generator to be purged of hydrogen and depressurized maintaining a CO2 cover gas.*

*On Friday 08/10/01 at about 2:30PM, Unit 3 was brought to mode 2 in an orderly fashion and the generator purged with CO2. The unit was brought down to mode 2 at a rate of about 10% per hour, using the normal operating procedure, 3-GOP-103, "Power Operation to Hot Standby." The "Fast Load Reduction Procedure," 3-ONOP-100, was never entered. The weld was repaired using the weld overlay procedure outlined in CR01-1364 Interim Disposition #1.*

*The main generator hydrogen system is described in Section 10.1 of the UFSAR. The UFSAR does not reference any allowable leak rates and there are no Technical Specifications with regard to hydrogen leakage. There are no adverse effects on the Turkey Point FSAR and Technical Specifications. The concern for hydrogen leakage is in regard to the potential for adverse personnel and industrial safety. Measures (forced ventilation) were taken to maintain safety; therefore, shutdown for repairs was a conservative and prudent action. The decision to shutdown was not based on operability or safety concerns, but rather on establishing the necessary conditions to facilitate repairs.*

*In accordance with NEI-99-02, if a degraded condition is identified more than 72 hours prior to the initiation of a plant shutdown, then the shutdown is considered a planned shutdown. The condition, necessitating the shutdown of Unit 3, was initially identified on July 11, 2001 (30 days prior to the actual shutdown). Moreover, the possibility of the need to shutdown for repairs was recognized just days later and limits were established to trigger that action (a plan established). In addition, repair efforts, including shutdown contingency plans, were ongoing throughout that thirty-day period. Does this situation qualify as a "planned" shutdown as suggested by NEI-99-02 FAQ 277?*
*Response: Yes, this is a planned shutdown in that the condition did not require "rapid response" (see NEI 99-02 p. 20 line 1-3)*

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